BEFORE THE PUBLIC UTILITIES
COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development.	OIR 01-10-024 (Filed October 25, 2001)

PRE-WORKSHOP COMMENTS

OF THE INDEPENDENT ENERGY PRODUCERS ASSOCIATION

ON MARKET PRICE REFERENTS (MPR):

MPR METHODOLOGIES TO DETERMINE THE

LONG-TERM MARKET PRICE OF ELECTRICITY FOR USE IN CALIFORNIA

RENEWABLES PORTFOLIO STANDARD (RPS) POWER SOLICITATIONS

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April 9, 2004

BEFORE THE PUBLIC UTILITIES
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Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development.	OIR 01-10-024 (Filed October 25, 2001)

Pre-Workshop Comments of the Independent Energy Producers Association

On Market Price Referents (MPR):

MPR Methodologies to Determine The Long-Term Market Price of Electricity For Use In California Renewables Portfolio Standard (RPS) Power Solicitations

Pursuant to the California Public Utilities Commission (CPUC) Staff's March 22, 2004 White Paper, "Discussion on Market Price Referents", the Independent Energy Producers Association (IEP) submits these pre-workshop comments with respect to the estimates of the "proxy plant" inputs to be used to derive a reliable Market Price Referent (MPR) for use in California Renewables Portfolio Standards (RPS) power solicitations.

In summary, we offer four opinions for these proceedings. First, it is our view that, at least conceptually, the appropriate benchmark plant for the MPR should be the marginal, new, fossil fuel facility that is displaced as a result of renewable energy investments, i.e. neither the average nor the most efficient new fossil fuel facility. Such a marginal new facility would likely incur capital costs and operating costs (including costs associated with siting, emissions, remediation, and hedging) that are significantly higher than those proposed as the preliminary MPR. Second, it is our view that recent transactions regarding fossil fuel facilities can provide relevant information with which to estimate the inputs to the MPR identified in the White Paper, or to assess the reasonableness of the inputs identified through other means. Third, it is our view that a relevant source of information for estimating the combined cycle "proxy plant" inputs for the baseload MPR is provided by a recent transaction involving Southern California Edison (SCE): the Purchase Power Agreement (PPA) between SCE and Mountainview Power Company (Mountainview), approved by the CPUC on December 18, 2003, and by the Federal Energy Regulatory Commission (FERC) on February 25, 2004. Fourth, using information from the Mountainview PPA along with other relevant modifications to the White Paper's MPR computation would result in an increase in the baseload MPR from $53.65/MWh to $65.16/MWh. This analysis also indicates that a substantial increase in the White Paper's computation of a gas-fired peaking MPR is also needed.

Attached for reference and incorporated herein in IEP's pre-workshop comments, IEP offers for the Commission's consideration the **REPORT OF DAVID W. DERAMUS, PH.D. REGARDING PROPOSED ADJUSTMENTS TO MARKET PRICE REFERENT METHODOLOGY.** Dr. DeRamus' Report primarily addresses the baseload MPR methodology in deriving an alternative to the CPUC Staff's proxy plant estimate, although it also addresses the peaking MPR methodology. As a consequence, IEP believes that its comments on the proposed baseload MPR methodology and concerns raised regarding its accuracy also applies to the matter of determining a peaking facility MPR, although additional research is needed in order to accurately estimate an alternative peaking MPR.

Dated: April 9, 2004

Respectfully submitted,

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ATTACHMENT A:

REPORT OF DAVID W. DERAMUS, PH.D.
REGARDING PROPOSED ADJUSTMENTS TO MARKET PRICE REFERENT MEHTODOLOGY

SUBMITTED ON BEHALF OF THE
INDEPENDENT ENERGY PRODUCERS ASSOCIATION

BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

REPORT OF DAVID W. DERAMUS, PH.D.
REGARDING PROPOSED ADJUSTMENTS TO MARKET PRICE REFERENT METHODOLOGY

SUBMITTED ON BEHALF OF THE
INDEPENDENT ENERGY PRODUCERS ASSOCIATION

APRIL 9, 2004

(1) Pursuant to the California Public Utilities Commission (CPUC) March 22, 2004 White Paper, "Discussion on Market Price Referents," the Independent Energy Producers Associations (IEP) has asked me to present my opinion with respect to the estimates of the "proxy plant" inputs to be used to derive a reliable Market Price Referent (MPR) for use in the California Renewables Portfolio Standards (RPS) power solicitations.

(2) In summary, based on my review of the available information, I have come to four primary conclusions. First, at least conceptually, the appropriate benchmark plant for the MPR should be the *marginal* new fossil fuel facility that is displaced as a result of renewable energy investments, i.e. neither the average nor the most efficient new fossil fuel facility. Such a marginal new facility would likely incur capital costs and operating costs (include costs associated with siting, emissions, remediation, and hedging) that are significantly higher than those proposed as the CPUC's preliminary MPR. Second, recent transactions regarding fossil fuel facilities can provide relevant information with which to estimate the inputs to the MPR identified by the CPUC, or to assess the reasonableness of the inputs identified through other means. Third, a relevant source of information for estimating some of the combined cycle "proxy plant" inputs for the baseload MPR is provided by a recent transaction involving Southern California Edison (SCE): the Purchase Power Agreement (PPA) between SCE and Mountainview Power Company (Mountainview), approved by the CPUC on December 18, 2003, and by the Federal Energy Regulatory Commission (FERC) on February 25, 2004. Fourth, using information from the Mountainview PPA along with other relevant modifications to the CPUC's MPR computation would result in an increase in the baseload MPR from $53.65/MWh to $65.16/MWh. This

analysis also indicates that a substantial increase in the CPUC's computation of a gas-fired peaking MPR is also needed.

1. THE APPROPRIATE BENCHMARK FOR THE MPR IS A MARGINAL FOSSIL FUEL PLANT

(3) One of the goals expressed by the CPUC in the White Paper is the stimulation of substantial technological change towards achievement of the RPS. In order to achieve that objective, the MPR needs to be set sufficiently high in order to allow new entry of renewable resources into the California energy market. If the MPR is set too low, insufficient renewable energy technology will be developed and implemented, an artificially low (below market) value will be placed on this technology, and limited public funds will be insufficient to support the amount of renewable energy investment required by making up the difference between the below-market value established by the MPR and the actual costs required to bring this technology to market.

(4) As a general principle, the MPR should reflect the production costs associated with the marginal (i.e. *least* efficient) generating units that would be replaced by renewable generation – and the capital costs that would be associated with the development of a marginal new facility (i.e. *most* expensive) in the absence of renewables. The principle of the market price being set by the marginal market participant – the participant that just clears the market – is a fundamental principle of economic analysis and applies equally to this context. For example, if the MPR is based on the cost of the *average* new fossil fuel plant, renewable suppliers with long-run total costs above that amount would not participate in the market (but for the SEP), while additional fossil fuel plants with similar above average costs would participate in order for the market-clearing amount of supply to be provided. In effect, if the MPR is set based on the cost of the average fossil fuel plant, utilities would obtain renewable energy at a below market-clearing MPR, while more expensive fossil fuel generation sets the actual market-clearing price.

(5) By contrast, if the MPR is set based on the long-run cost of a *marginal* new fossil fuel plant, all renewable suppliers submitting below that price – those that provide an economical alternative to fossil fuel investments – would be accepted, and the market-clearing amount of renewable investment would occur. This is consistent with the purpose of the MPR to reflect the price a utility would pay for a marginal conventional fossil fuel resource, which the renewable resources proposed under the RPS bidding process would replace.[1] As a consequence, the appropriate

[1] CPUC White Paper on Market Price Referents, p. 5.

MPR is the displaced fossil fuel alternative, not the most efficient or even the average fossil fuel alternative: the displaced fossil fuel alternative will be the high-cost alternative, i.e. it will likely be located in urban areas with restrictive emission limits, high environmental mitigation requirements, high fuel delivery costs, and (potentially) high transmission costs.

(6) Using this methodology to set the MPR, the SEP would then serve its intended purpose of encouraging a greater level of investment in renewable energy supply than a competitive market would otherwise produce. Under competitive power procurement conditions, generators submitting renewable bids below the MPR would not require a Supplemental Energy Payment (SEP) in order to participate in the market; while generators with long-term costs above the MPR would require a SEP in order to be able to provide the market with a source of supply. This application of fundamental economic principles to the RPS power solicitation process is particularly applicable, since the MPR does not establish the price that suppliers will actually receive, but rather simply sets a market price ceiling above which a SEP is necessary in order to ensure a supply of renewable energy that is consistent with the goals set by the Energy Action Plan.

2. THIRD-PARTY CONTRACTS PROVIDE USEFUL INFORMATION FOR ESTABLISHING A RELIABLE MPR

(7) Actual market contracts can provide a reasonable, reliable, and objective basis for determining market values. In the context of arm's length long-term contracts between independent firms, utilities and other power producers have invested significant resources in negotiating the terms of such contracts. The outcome of such arm's length negotiations provides reliable, unbiased information about future electricity prices: suppliers would not enter into contracts that failed to provide adequate returns, and purchasers would not enter into contracts that provided excessive returns. In addition, related party contracts subject to the review and approval of relevant regulatory bodies may also provide a reasonable basis for determining the MPR. Such regulatory review and approval is presumably predicated on a determination that the prices reflected in the related party contracts at issue are consistent with arm's length prices and are "just and reasonable" (or otherwise in conformity with the applicable regulatory standard).

(8) The CPUC argues that at the present time, there is not a sufficient number of contracts meeting the statutory requirements with which one can determine the MPR.[2] However, a high standard of

[2] CPUC White Paper on Market Price Referents, p. 5, citing D.03-06-071, p. 16.

comparability is not necessary in order for third party contracts to provide relevant information for determining the MPR, and there are many such contracts that can be useful for these purposes. For example, many out-of-state third party power contracts contain contractual provisions that can serve as reasonable proxies for the basic inputs with which to determine a MPR (e.g., the cost of capital, O&M costs, or heat rates). Furthermore, if there are systematic differences between third-party benchmark contracts and a reasonable MPR, such differences can often be adjusted with reasonable accuracy (e.g., adjusting for differences in fuel transportation costs).

(9) I am not suggesting that the "proxy plant" methodology proposed by the CPUC be discarded. Quite the contrary, there are many positive aspects to the methodology, and it is grounded in fundamental principles of valuation. However, the CPUC's "proxy plant" calculations can and should be augmented with information provided by third-party contracts in order to derive a more reliable MPR. In addition, such third-party contracts can also provide relevant insight into various contractual provisions that impose additional costs and risks that should be taken into consideration in establishing the MPR, even if these additional costs and risks are not explicitly (or easily) quantified.

3. THE MOUNTAINVIEW PPA CAN PROVIDE RELEVANT INFORMATION TO UPDATE THE PROPOSED MPR

(10) One transaction that provides useful information with which to evaluate the CPUC's proposed MPR is the recently approved PPA between SCE and Mountainview, approved by FERC on February 25, 2004. The Mountainview PPA is a cost-based contract providing for recovery of investment, fixed and variable costs, and a regulated rate of return, over the 30-year life of the contract. The PPA is structured as a tolling agreement, giving SCE the responsibility for gas procurement, hedging, and plant dispatch.

(11) The CPUC approved the PPA because it found the contract to be "in the public interest," and because "the economics of Mountainview make it a cost-effective resource to meet SCE's short-term and long-term resource needs." The CPUC found that the capital recovery mechanism set forth in the PPA is reasonable and that it is appropriate for Mountainview to maintain a capital structure and earn a return on equity equal to those from SCE. In short, the CPUC concluded that Mountainview is "a very good deal for Edison's customers."[3] In addition, SCE's experts

[3] CPUC Decision 03-12-059, Opinion Granting Southern California Edison Company's Application to Acquire Mountainview Power Company,

reported that Mountainview costs are attractive relative to cost expectations of several expert analysts and energy agencies.[4] SCE similarly stated that the transaction allowed them to acquire capacity at a "substantial discount below published benchmarks and the cost of similar recently completed facilities."[5]

(12) While I disagree with the CPUC's (and FERC's) approval of the Mountainview transaction on competitive grounds, the PPA nevertheless provides useful information for evaluating the MPR, although significant adjustments to the terms of the contract are necessary in order to improve comparability. SCE submitted a significant amount of (publicly available) cost information during the Mountainview proceedings, including various expert reports. As discussed in more detail below, the Mountainview PPA provides relevant information with which to estimate investment cost, cost of capital, capacity factors, and heat rates for the MPR methodology. Of course, the information provided in the Mountainview PPA must be adjusted (when necessary) in order to reflect actual market values comparable to those envisioned in the MPR standard. For example, Mountainview's capital costs are below market, as evidenced by SCE's own statements as well as by the fact that it purchased a distressed asset from an independent generator (the transaction has been referred to as a 'fleeting opportunity,' reflecting an unusually large discount resulting from the bargain – below-market – price of the acquired assets, unlikely to be obtainable in the future).

(13) In addition, various contract provisions in the Mountainview PPA indicate that there are additional costs and risks that should be included in the MPR in order to appropriately reflect all of the costs associated with a utility's procurement of fossil fuel generation. I should note that many of these costs and risks are not specific to the Mountainview PPA but rather apply to fossil fuel procurement more broadly. Many of these costs and risks indicate that using the Mountainview PPA to establish the MPR is likely to underestimate the actual costs to consumers of acquiring power from Mountainview, since the PPA does not include a number of capital and operating costs for which no information is currently available, nor does it fully account for all of the additional risks borne by ratepayers under the PPA. Furthermore, using information from the Mountainview PPA is likely to result in an underestimate of the MPR, due to its cost and efficiency relative to the "marginal proxy plant" standard suggested above.

LLC (MVL) Either as a Wholly Owned Subsidiary and to Enter into a Power Purchase Agreement with MVL for Electricity from the Mountainview Power Project, or as a Utility-Owned Generation Facility (Mountainview Decision), p. 23-24, 27, 64-65, and Comments.

[4] Affidavit of Joseph B. Wharton for Southern California Edison (Attachment F) at 47.

[5] Southern California Edison Application to the California Public Utilities Commission A.03-07-032, July 21, 2003, p. 13.

4. PROPOSED REVISIONS TO PROXY PLANT INPUTS FOR COMBINED CYCLE GENERATION

(14) The purpose of this section is to review each of the inputs identified in the CPUC White Paper and identify specific issues that are important to address in order to derive more reliable estimates. I have reviewed the available information in these proceedings, including the comments submitted by other participants (as identified in Appendix B of the CPUC White Paper), and I reference the Mountainview PPA where applicable to each of the inputs below. I should also note that my analysis of these issues is a work in progress, and as a consequence, I do not consider my comments below to be exhaustive. With additional information and analysis, I may revise and supplement the figures and opinions expressed herein. In Section 5, below, I demonstrate the impact of these issues on the MPR. As further discussed below, this figure provides a lower bound estimate for the MPR, due to the numerous unquantified costs and risks associated with the displaced fossil fuel alternative.

4.1 Initial Investment Cost (Capital Cost)

(15) The proposed MPR by the CPUC includes an initial investment cost of $650/kW to plan, permit, construct, and start up a new combined cycle facility. The CPUC found that the CEC's report provided a reasonable and objective starting point for plant investment costs, with estimated total in-service capital costs of $616/kW, although it also found that adjustments were necessary. The CEC analysis did not include a number of costs that would have a significant impact on total investment costs, including:

- Regional and site-specific permitting and infrastructure
- Gen ties
- Decommissioning costs
- Working capital
- Capital additions
- Corporate and financial services overhead
- Other extraordinary costs

(16) Site-specific costs include the cost of emission offsets, mitigation measures, water lines, pipelines, substations, transmission lines, and induction equipment. For example, emission

offset costs can add over $40/kW to the above total costs.[6] Permitting costs represent an additional cost of $10/kW.[7] Plants requiring dry cooling would have an additional cost of at least $50/kW.[8] As the CPUC noted, direct assignment transmission facilities (gen ties) are necessary to connect the generation facility to the grid and should be considered a component of the generation facility.

(17) Decommissioning costs have also not been included in the assessment of capital costs. However, even though such costs are not paid up-front, they clearly constitute capital investment costs. In long-term bilateral contracts, utilities have included decommissioning costs in the rate base. Since they are ultimately recovered from ratepayers, these costs should be included in the long-term price of electricity when determining the MPR.[9]

(18) The CEC analysis also did not include the working cash reserve necessary to finance expenditures in production facilities. By contrast, the Mountainview PPA includes working cash in the rate base equivalent to one-eighth of the monthly O&M expenses, citing FERC precedent.[10]

(19) Overall, the proposed MPR does not include extraordinary costs associated with bringing an average plant in-service, nor does it include additional capital investments that are ultimately recovered from ratepayers. Although such costs will differ by plant, it is unrealistic to assume that they will be zero (especially from the perspective of a marginal investment project), resulting in an underestimate of the market price of electricity.

(20) As discussed above, it is appropriate to explicitly use existing long-term power contracts in assessing proxy plant calculations. The CPUC found that the price in the Mountainview transaction "reflects capital costs below that of the market" and that "Mountainview is clearly cost-effective,"[11] an assessment that supports the use of the Mountainview transaction in determining the MPR (although it also clearly indicates that adjustments are necessary in order to estimate capital costs that are at least consistent with market averages, if not in line with the marginal proxy plant). According to the CPUC, SCE reported a total in-service cost of $667/kW. However, it is my understanding that total construction costs for the plant were expected to be

[6] "Regional Cost Differences Siting New Power Generation in California." Aspen Environmental Group for the CEC, December 2002.

[7] Calculated from "Siting Fee Study: A Report to the Legislative Analysis's Office." The estimate is conservative since it divides the total estimated permitting cost by a 1000-MW project capacity, assuming the costs do not increase with plant capacity.

[8] See CEERT testimony filed on April 1, 2003 at 2-13, 14, 15 in R.01-10-024. Based on Calpine and Duke plants.

[9] The CPUC adopted SCE's proposal to include Mountainview site-specific decommissioning costs in its GRC filings (Mountainview Decision). FERC has also argued in Southern California Edison that the salvage cost associated with the units should be an appropriate cost item under the PPA. 106 FERC ¶ 61,183.

[10] Carolina Power & Light Co., 6 FERC ¶ 61,295 (1979).

[11] Mountainview Decision, p. 40.

approximately $1,000/kW, with the difference reflecting a substantial below-market discount resulting from the distressed nature of the project. The total cost reported by SCE also includes 14% of Allowance Funds Used During Construction (AFUDC), well above the 10% AFUDC estimated by the CEC.

(21) Although SCE will be responsible for decommissioning the Mountainview facility, the capital cost reported by SCE did not include decommissioning costs. Assuming decommissioning costs of approximately 10% of the cost of the plant at the end of the contract, the present value of the decommissioning costs would increase the total investment cost by $32/kW.[12] In addition, SCE did not include $12/kW for a 17.5 mile natural gas pipeline expansion that SCE would need to construct.

(22) In using such information to determine the MPR, it is also important to quantify the expected value of contingency provisions that will affect total in-service costs. For example, the CPUC indicates that under the terms of the Mountainview PPA, SCE may seek pre-approval by the CPUC to include expenditures in capital additions or betterments. In the PPA, the cost of construction is subject to a capital cost limit of 5% over the expected capital cost. Neither of these contingencies are included in SCE's in-service cost identified above.

(23) Finally, in the Mountainview proceeding, SCE's experts presented a benchmarking analysis as a market test for the transaction. Dr. Wharton found that the average capital cost for 11 comparable plants in California was $46/kW above Mountainview's capital cost.[13] All of this indicates that Mountainview can provide useful information, subject to adjustment, with which to estimate the appropriate capital cost for the MPR.

4.2 Cost of Capital

(24) In deriving its preliminary estimate of the MPR, the CPUC uses a cost of capital of 7.5% for a 20-year project. This cost of capital assumes – incorrectly – that the appropriate benchmark is a project that is financed entirely with debt and without any equity financing. By contrast, the CEC calculated the cost of capital as a weighted average of both debt and equity, using 16% as the cost of equity and 7.8% as the cost of debt to obtain a weighted average cost of capital of 11% (with a 60% debt structure).

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[12] Assumes decommissioning costs are collected over the plant's 30-year life and secured at a long-term risk-free rate of 2.5% (Treasury inflation-indexed bonds).

[13] The capital cost in Dr. Wharton's calculations does not include AFUDC and decommissioning costs.

(25) As noted above, one can look to actual transactions in order to assess the CPUC's methodology. In actual transactions, the cost of capital is significantly higher than the one used in the MPR calculations. In the Mountainview PPA, for example, SCE used the rate of return on capital that was established by the CPUC. In Decision 02-11-027, the CPUC adopted a 9.75% return on investment applicable to SCE's assets. This value, well above the CPUC assumption for the MPR, is derived using 8.19% as the cost of long-term debt, 11.60% as the cost of equity, and 6.51% as the cost of preferred stock. Furthermore, while the MPR calculations assume annual capital recovery charges, in setting SCE's rate of return, the CPUC calculates the return on investment on a monthly basis. Whether the rate is compounded monthly or annually will obviously make a difference in terms of the effective annual rate. In order to obtain the effective annual rate using monthly compounding, the 9.75% nominal annual rate applied to the Mountainview PPA translates into a 10.20% effective annual rate.[14]

(26) More importantly, the CPUC uses the wrong methodology to calculate the cost of capital for use in the MPR. In cost-based long-term contracts, the actual cost of electricity charged to customers must cover not only the rate of return on capital, but also federal and state taxes and adjustments for book depreciation. Since the MPR is meant to reflect the total cost of the electricity produced, the capital recovery factor used to calculate the MPR should also be adjusted to account for taxes and depreciation. Instead, the CPUC only uses the rate of return for shareholders and debt holders. In other words, a seller with exactly the same costs as in the MPR would not obtain, after taxes and depreciation, the rate of return assumed in the MPR – and the rate of return would be substantially below that obtained in the Mountainview PPA.

(27) The Mountainview transaction illustrates the difference between the cost of capital for the project and the return for the investor. The CPUC approved rate of return is 9.75% (compounded monthly). However, from the annual capital recovery charges paid by SCE, the internal rate of return (IRR) of the project is 14.9%.[15] This is the actual cost of capital implied by the price of electricity purchased by SCE. The MPR should include this IRR – or an equivalently adjusted capital recovery factor – to accurately reflect utilities' foregone costs of procuring electricity.

4.3 Capacity Factor

(28) The CPUC makes use of the 92% capacity factor for combined cycle plants estimated by the CEC. This figure reflects ramping and estimates of forced and planned outages, but it is also

[14] Mountainview Rate Schedule contained in proposed PPA, SCE Application A.03-07-032 Appendix B, pp. 47-50.
[15] Calculated from Appendix B (Mountainview Decision).

inconsistent with the CEC's forecasts for combined cycle plant operations.[16] The CEC simulated the wholesale spot market for electricity for 2005, using five different scenarios. Under the most pessimistic scenario (lowest reserve margin and highest prices), combined cycle units would run at an average capacity factor of 78%. Above a 78% capacity factor, they would not be economical for the market prices estimated by the CEC.

(29) Apart from technological and economic reasons, the capacity factor should also take into account third party contractual arrangements. For instance, in the Mountainview transaction, SCE bears the risks of Mountainview failing to deliver for reasons of *force majeure*.[17] Although it is difficult to quantify the probability of such events, contractual agreements of this type increase the cost of the electricity purchased by reducing the expected capacity factor.

4.4 Heat Rate

(30) The heat rate of a combined cycle unit in "new & clean" condition is generally in the range of 6900 Btu/kWh to 7100 Btu/kWh. However, it is well-known that unit performance is considerably affected by factors such as transient operating conditions, weather conditions, and unit degradation.

(31) Transient operating conditions include start-ups, shut-downs, partial forced outages, ramping from outages, damages in the unit's components, and deep load changes. The increase in heat rates under partial loads can be estimated with the use of correction curves from the individual plant. Weather conditions include ambient temperature, humidity, barometric pressure, and natural gas fuel conditions. Unit degradation occurs over time and can be estimated with the degradation correction curves obtained from the equipment manufacturer. In long-term contracts based on heat rates, the degradation correction curves are used to adjust the measured heat rate before comparing them to the "new and clean" condition benchmark.

(32) In order to assess fuel costs in the MPR, heat rates should be corrected from the "new and clean" condition to include the factors mentioned above. TURN recommends the use of a heat rate that is 5% above the "new and clean" heat rate. Correction curves and degradation correction curves from the unit would provide estimates of the appropriate adjustment over the life of the unit.

[16] "2002-2012 Electricity Outlook Report". CEC, pp. 36-37.
[17] Mountainview Rate Schedule, p. 36.

4.5 Fuel Cost

(33) The CPUC mentions three primary fuel price parameters to consider:

- Natural gas price
- Hedge value
- Transportation costs

(34) The importance of natural gas prices in the determination of the MPR calls for the use of all available information regarding future gas prices. In theory, the most appropriate and unbiased source of information is provided by long-term forward, future, or swap gas contracts. However, as the CPUC notes, forward markets for natural gas are not fully developed and do not generally involve lengthy durations. Nevertheless, the information provided by future markets should still be incorporated into the analysis, together with other available forecasts, since arbitrage opportunities lead contract prices to reflect all of the information available in the market. In contrast, gas forecasts are not subject to a similar market discipline, since market participants do not trade at those prices. The CPUC notes that during the last 5 years, forward prices for natural gas may have exceeded some published natural gas price forecasts. Nevertheless, independent of these past market outcomes, utilities still hedge their positions using futures or swaps, not forecasts – and as a consequence, the use of forward prices will reflect more accurately the cost of the commodity in the MPR.

(35) The CPUC is required to establish a MPR that considers the "fixed-price fuel costs associated with fixed-price electricity." Since the cost of renewable resources does not have the same volatility as gas prices, the MPR should be measured in equivalent terms. That is, the value of renewable resources is not only given by the replacement of alternative resources (i.e., fossil fuel), but also by the elimination of costs that market participants would otherwise incur as a result of market volatility. While the fossil fuel replacement cost is given by a price forecast, the cost of volatility is given by the hedging costs incurred by generators and utilities. Without including foregone hedging costs, using forecasts of natural gas prices alone will not reflect the costs of uncertainty.

(36) Coinciding with the improvement in their credit ratings, some utilities argue that the long-term cost of ownership should be based on an assumption that the project would be developed by a creditworthy supplier with investment grade credit who is unlikely to have significant fuel hedging costs. However, hedging costs should take into account the actual costs ratepayers face from utilities' gas procurement. In reality, hedging always involves certain costs, even for

creditworthy utilities, and those costs should be included in the MPR. For instance, TURN reports that SCE spent approximately $0.80/MMBtu to hedge its exposure to gas costs in 2002-2003.[18] The MPR should include the costs utilities incur from hedging against natural gas prices.

(37) As the CPUC noted, capital markets for natural gas are not fully developed and do not currently offer 20-year hedging instruments. However, the MPR only requires a measure of hedging costs, not the hedging instrument itself. A proxy for hedging costs may be estimated from the increased financing costs utilities and power producers face in capital markets due to the volatility of fossil fuel prices. One way to measure these increased costs may be to assess the impact of the volatility of fossil fuel prices on the market value of power producers.

(38) Finally, transportation costs represent a significant component of delivered natural gas prices. For instance, between 1993 and 1999, the price of natural gas sold at the southern California border was approximately 10% above the San Juan Basin price. Due to transportation and storage constraints during 2000 and 2001, the price at the southern California border was often double the San Juan Basin price. In addition, there are also costs associated with intrastate gas transportation, which can be estimated using industry data and historic costs.[19]

4.6 O&M Cost

(39) Operation and Maintenance costs can be assessed in the three categories typically specified in long-term electricity contracts:

- Fixed O&M costs
- Variable O&M costs (excluding fuel)
- Pre-authorized O&M charges

(40) Commenters in these proceedings have provided estimates of fixed and variable O&M costs. Estimates of fixed costs range between $1.1/MWh and $2.0/MWh. Industry information suggests that these figures may be underestimated. In the Mountainview proceeding, for instance, SCE's expert Dr. Wharton reported results from his benchmark analysis that fixed O&M costs average $18/kW-year (approximately $2.2/MWh), but these costs have been as high as $36/kW-year. Variable O&M costs have been reported in the range of $2.3/MWh to

[18] Renewable Portfolio Standard Implementation Issues, Prepared Testimony of William B. Marcus on Behalf of The Utility Reform Network, April 1, 2003 (TURN), p. 7.
[19] The CEC forecast of fuel costs mentioned above includes transportation.

$5.2/MWh. However, some fixed and variable O&M costs in PPAs have been categorized as pre-authorized charges.

(41) Pre-authorized expenses are passed directly from the seller to the buyer. They are pre-committed expenses outside of sellers' control. The Mountainview PPA included a list of twelve specific costs included in the "pre-authorized" category (e.g., property taxes, governmental charges, insurance costs, environmental costs, added facilities, etc.). However, these costs were not quantified in the Mountainview PPA.

(42) Another source of costs for power producers that has not been mentioned in the MPR discussion is the hedging costs associated with emission permits. During the California electricity crisis, the cost of these permits soared along with the number of generators facing emission constraints. The risks associated with permit costs is similar in nature to the burden imposed by fluctuating fuel prices and deserves a similar treatment in the MPR calculations.

4.7 Other initial investment adders

(43) In electricity long-term contracts, the buyer has a number of costs not included in the categories above. These costs are part of the costs of obtaining a long-term supply of energy and should be taken into account in the MPR. The Mountainview PPA provides a few examples of such additional costs:

- *Force majeure*: in the event that the seller is unable to carry out its obligations by reason of *force majeure*, the buyer would suffer from higher costs than those estimated in the MPR.
- Renegotiation: in the case that the seller has additional costs due to changes in applicable laws, the PPA would be renegotiated under CPUC supervision.
- Incentive payments: a number of incentive payments (e.g., availability and heat rate incentives) can increase the final costs charged to customers.

(44) While often not explicitly identified, long-term contracts such as the Mountainview PPA also present the risk that ratepayers may be saddled with stranded costs under certain contingencies. For example, within the time horizon of a 30-year contract such as the Mountainview PPA, emerging technologies may become commercially available that would leave the buyer with a stranded asset. Subject to regulatory approval, the costs associated with the stranded asset may ultimately be borne by ratepayers. While such risks may be difficult to quantify, they are associated with implicit or explicit costs that should be taken into consideration in determining an appropriate the MPR.

5. PROPOSED REVISIONS TO COMBINED CYCLE BASELOAD MPR

(45) Based on the discussion above, this section provides a minimum suggested revision to CPUC's baseload MPR estimate, using the Mountainview PPA, the CPUC's overall proxy plant methodology, and other revisions identified by various parties. This estimate should be seen as a minimum revision to CPUC's MPR estimate, since it does not include a number of additional costs (and risks) associated with fossil fuel alternatives that have not been quantified, as discussed above. In addition, this estimate is not based on using a *marginal* proxy plant as the appropriate point of reference, even though (as discussed above) this would be the appropriate basis for establishing the MPR, since the most expensive fossil fuel investment would be the displaced alternative to the market-clearing renewable source of energy.

(46) Table 1 shows the individual cost inputs and total estimated cost for both the CPUC's MPR estimate and the minimum suggested revision using information from the Mountainview PPA. The comparable investment cost implied by the Mountainview PPA is approximately $795/kW. This figure includes a total plant-in-service cost of $667/kW plus decommissioning costs, the cost of a 17.5 mile pipeline, estimates of emission offset costs, permitting costs, and an allowance of 5% over the expected capital cost, as described above. This estimate is conservative, since it assumes the plant does not require dry cooling, and it does not consider gen ties costs, capital additions, and other necessary investments in infrastructure. The figure is also well below the original planning and construction cost estimate of $1,000/kW and the plant-in-service benchmarking analysis performed by SCE's experts in the Mountainview proceedings.

(47) The revision to the MPR in Table 1 also includes a cost of capital of 14.9%, consistent with the total return of the Mountainview project, adjusting for taxes and depreciation. The life of the project is assumed to be 20 years, similar to a renewable project. Using a 20-year life of the project is further justified based on the pace of technology development for renewable energy sources that would likely render the plant technologically or economically obsolete within that time period.

(48) The 78% capacity factor in Table 1 considers not only plant outages, but also economic dispatch of the plant according to the CEC simulations. The heat rate equals the maximum heat rate allowed in the Mountainview PPA, 7210 Btu/kWh, plus TURN's 5% adjustment. These assumptions are meant to take into account transient operating conditions, weather conditions,

and unit degradation. Finally, in Table 1, I include CPUC's assumptions for natural gas prices and O&M costs, since these were not fully specified in the Mountainview PPA.

(49) The total cost obtained for combined cycle generation using the above assumptions is $65.16/MWh. This costs is considerably higher than the CPUC's preliminary estimate of $53.65/MWh. The difference is mainly due to the CPUC's use of underestimated investment costs and cost of capital.

Table 1: Modification of Baseload MPR using Terms of Mountainview PPA and Other Adjustments

Inputs	MPR (CPUC)	Modified MPR Using Terms of Mountainview PPA	Methodology
Capital Cost per kW ($/kW)	650	795	Mountainview PPA
Heat Rate (Btu/kWh)	7400	7570	Mountainview PPA + 5%
Fuel Cost ($/MMBtu)	5.3	5.3	CEC forecast, including hedge
Capacity Factor	92%	78%	CEC forecast
Cost of Capital	7.5%	14.9%	Mountainview PPA IRR
Years	20	20	CPUC assumption
Capital Recovery Factor (CRF)	0.098	0.159	As computed in CPUC White Paper
Capital Recovery ($/kW-year)	63.76	126.52	CRF x Capital Cost
All-in Costs			
O&M ($/MWh)	6.3	6.3	CPUC estimate
Capital Cost: ($/MWh)	7.9	18.5	Capital Recovery/(8760 x Cap. Factor)
Fuel: ($/MWh)	39.4	40.3	Fuel Cost x Heat Rate
Total ($/MWh)	**53.65**	**65.16**	Combined Cycle Generation

6. PROPOSED REVISIONS TO GAS-FIRED PEAKING MPR

(50) While I have not performed a similar analysis of a comparable third-party transaction involving a gas-fired peaking unit, it is worthwhile noting that most of the issues identified above apply equally to determining the peaking MPR. Furthermore, the impact of these issues on the peaking MPR is likely to be even more substantial than the impact on the baseload MPR. Using the 14.9% total effective rate of return from the Mountainview PPA would alone increase the peaking unit MPR from $115/MWh (as computed by the CPUC) to $148/MWh.

(51) Making reasonable adjustments as identified above to the peaking unit capital costs used by the CPUC would also have a significant impact on the MPR. For example, using the CEC's estimated capacity factor of 7.5% for 2002 (well above the capacity factor forecasts for 2004-2005) instead of the 10% capacity factor used in the CPUC's computation will further increase

the MPR from $148/MWh to $177/MWh; and including 10% decommissioning costs in addition will further increase the MPR to $184/MWh. These figures do not include additional emission offset costs, permitting costs, and capital cost allowances, as discussed above, which would further increase the peaking MPR.

(52) In addition, it appears that the peaking unit capital cost estimate used by the CPUC of $475/kWh is substantially lower than appropriate benchmarks indicate. Some of this may be driven by the fact that the CPUC assumed a peaking unit with a capacity of 120 MW, while many recent new additions have a substantially smaller capacity in the range of 45 MW. For example, tax assessor records for 2002 indicate that the assessed value of six new 45 MW peaking units[20] is in the range of $41 – 50 million, corresponding to approximately $1,000/kWh, more than double the capital cost assumption used by the CPUC. While further analysis is necessary in order to more accurately estimate the necessary modifications, the above examples indicate that substantial revisions to the peaking MPR proposed by the CPUC are needed.

7. CONCLUSIONS

(53) In summary, the above discussion demonstrates that third-party contracts, and the Mountainview PPA in particular, can provide useful information with which to establish a more reliable estimate of the MPR. Using this information shows that the long-term market price for baseload combined cycle generation should be at least $65.16/MWh, well above the CPUC estimate of $53.65/MWh. Furthermore, the available information indicates that the gas-fired peaking MPR should be increased significantly as well. These calculations should also be regarded as a lower bound for the MPR. As a general matter, the MPR should be based on the market-clearing displaced fossil fuel alternative, which by definition would be the least efficient/highest cost alternative – a standard that has not been used in the analysis above. More specifically, the figures presented above do not include a large number of additional relevant costs, such as:

- Site-specific costs
- Gen ties
- Capital additions
- Costs associated with plants requiring dry cooling
- Working capital
- Corporate overhead

[20] Peaking plants located in King City, Yuba City, Feather River, Lambie, Creed, and Goosehaven.

- Additional gas transportation costs
- Pre-authorized expenses
- Hedging costs for emission permits and other risks
- Incentive payments
- Costs associated with *force majeure*
- Potential stranded costs
- Other extraordinary costs

(54) Additional research and analysis will be useful in order to accurately quantify these additional costs and update the estimates presented above.

<u>CERTIFICATE OF SERVICE</u>

I, Eric Janssen, am over the age of 18 years and employed in the City and County of Sacramento. My business address is 2015 H Street, Sacramento.

On April 9, 2004, I served the within document, **"Pre-Workshop Comments of the Independent Energy Producers Association On Market Price Referents (MPR): MPR Methodologies to Determine The Long-Term Market Price Of Electricity For Use In California Renewables Portfolio Standard (RPS) Power Solicitations",** in R.01-10-024, with electronic service, as prescribed in R.01-10-024, and personal service on the Assigned Commissioner and Assigned Administrative Law Judge, at San Francisco, California.

Executed on April 9, 2004, at Sacramento, California.

____
Eric Janssen

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R.01-10-024
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